414 Nicollet Mall
Minneapolis, MN 55401

July 31, 2023

—Via Electronic Filing—

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: COMMENTS
PERFORMANCE METRICS AND INCENTIVES
DOCKET NO. E002/CI-17-401

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Comments pursuant to the Minnesota Public Utilities Commission's May 26, 2023 Notice of COMMENT PERIOD in the above-noted docket.

We have electronically filed this document with the Commission, and copies have been served on the parties on the attached service list. Please contact Bridget Dockter at bridget.dockter@xcelenergy.com or (612) 337-2096 or Taige Tople at taige.d.tople@xcelenergy.com or (612) 216-7953 if there are any questions regarding this submission.

Sincerely,

/s/

BRIDGET DOCKTER
MANAGER, POLICY & OUTREACH

Enclosures
cc: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE COMMISSION INVESTIGATION TO IDENTIFY AND DEVELOP PERFORMANCE METRICS AND POTENTIALLY, INCENTIVES FOR XCEL ENERGY'S ELECTRIC UTILITY OPERATIONS

DOCKET NO. E002/CI-17-401

COMMENTS

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission these Comments in response to the Commission's May 26, 2023 NOTICE OF COMMENT PERIOD (Notice) in the above-referenced docket.

The Commission opened the following topics for comment:

1) *Should the Commission accept Xcel's 2021 & 2022 PBR Annual Reports? Do Xcel's reports address the requirements set forth by Commission Orders in this docket, including but not limited to:*
    - *Future metrics?*
    - *Development of an online utility performance dashboard?*
    - *Data collection on and/or reductions in upstream methane emissions?*
2) *From the three years of data that have been filed for each metric, how should a single baseline value be calculated? (Xcel is in the process of providing three years of baseline data for its interactive map. With respect to equity data, stakeholders should work through topics open for comment to create a path forward once data are filed). Please explain your reasoning and provide calculations of the baseline for each metric.*
3) *For which metrics, if any, should the Commission set targets and why?*
4) *Where applicable, by what methodology should targets be set? How often should targets be reviewed and potentially updated?*
5) *Where applicable, what are appropriate targets for the metrics?*

6) *What action should the Commission take on reporting the Company's Workforce Transition plan in Docket No. E002/M-22-265 rather than the instant docket?*
7) *How should the Commission evaluate the metrics that do not have three years of baseline data?*
8) *Are there other issues or concerns related to this matter?*

HISTORY

In 2015, the Legislature passed a Multi-Year Rate Plan (MYRP) statute.[1] On November 2, 2015, the Company initiated a general Minnesota electric rate case[2],seeking consecutive rate increases pursuant to the multi-year rate plan statute.[3] Subd 19 (a) of the statute allows that "the commission may also require the utility to provide a set of reasonable performance measures and incentives that are quantifiable, verifiable, and consistent with state energy policies." As part of that proceeding, we proposed new performance metrics addressing customer satisfaction, customer choice, environmental stewardship, and customer outage experience.

On June 12, 2017, the Commission issued an Order in the rate case approving a multi-year rate plan. In addressing our application, the Commission noted that "performance metrics are an important tool to preserve service quality and align utility incentives with ratepayer interests" and found that the rate case record was insufficient to "determine the adequacy of the Company s proposed performance metrics." The Commission thus opened the performance metrics investigation to "identify and develop performance metrics and standards, and potentially incentives, to be implemented during the multi-year rate plan," and as "the best venue for determining what combination of metrics and incentives, in addition to those already in the Company's QSP Tariff, would appropriately align utility and ratepayer interests."[4]

On September 22, 2017, the Commission issued a *Notice of Comment Period* in the present docket, soliciting input on topics related to performance-based utility regulation and instructing that the proceeding would be staged in two phases. The first phase would focus on collecting stakeholder input about (a) key goals for the electricity sector, (b) how performance against those goals is currently being measured, (c) which metrics or information should be used to determine whether the utility is meeting those key goals, and (d) what utility information or independent studies would aid in establishing achievable potential for performance against those key goals. The second phase would focus on how the Commission might use or apply

[1] Minn. Stat. § 216B.16, subd. 19 (2011, and modified in 2015).
[2] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-15-826, NOTICE OF CHANGE IN RATES (November 2, 2015).
[3] Minn. Stat. § 216B.16, subd. 19.
[4] FINDINGS OF FACT, CONCLUSIONS, AND ORDER, Docket No. E002/GR-15-826 (June 12, 2017) at 23.

performance measurements and standards and the potential for using financial incentives to drive the Company's performance.

The Commission issued a *Notice of Upcoming Process* on November 9, 2018 and its *Order Establishing Performance-Incentive Mechanism Process* on January 8, 2019. The Order adopted the Office of the Attorney General's (OAG) Performance Incentive Mechanism (PIM) Process and associated Goals-Outcomes-Metrics hierarchy. Also, the Order delegated authority to the Executive Secretary to issue notices, set schedules, and designate comment periods for the development of performance metrics and related reporting processes.

On September 18, 2019, the Commission issued an Order establishing performance metrics for the Company to track and report and instructed the Company to work directly with stakeholders to develop proposed calculations, verification, and reporting methods for those metrics. The Commission ordered the Company to file the proposed methodologies by October 31, 2019.

That Order instructed the Company to (1) work directly and collaboratively with interested parties to develop proposed, specific responses to calculate (to the extent not already developed), verify, and report on Commission-established metrics; (2) work with stakeholders on development of a future metric to measure workforce and community development impact; and (3) no later than October 31, 2019, file a description of the Company's proposed methodology for each of the metrics and a proposed schedule for reporting the metrics. For "future metrics," the Company and stakeholders were directed to provide an update on methodology development in the October 31, 2019 filing, including a proposed schedule for finalizing methodology and a timeline of when reporting is anticipated to begin. The Commission issued an Order approving the proposed metrics and methodologies on April 20, 2020.

In our 2021Annual Report with 2020 data, the Company requested to provide three data years (2021 through 2023 reports for 2020 through 2022 data) prior to developing the benchmarking criteria. The Commission agreed and approved the request as part of the 2021 Annual Report Order, issued on February 9, 2022. Annually thereafter, the Company has submitted updates in accordance with the most recent Commission Orders.

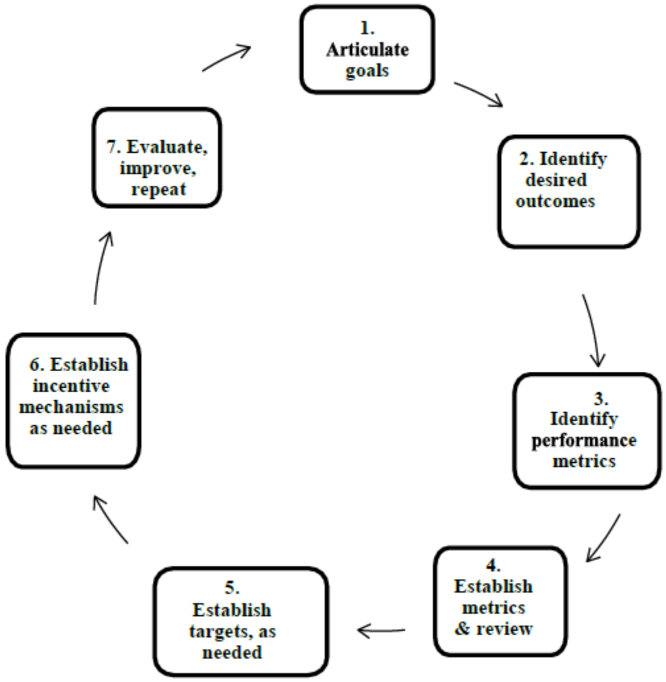
BACKGROUND

MYRPs are alternative rate tools that qualify as Performance Based Rates (PBR) because they encourage cost containment during the course of the plan, which in turn controls customer rates. By reducing rate case frequency, MYRPs also reduce regulatory burden. Other alternative rate tools in the Minnesota regulatory construct include rate riders, which provide utilities a path to timely recovery of actual costs for specific functions. These include fuel costs and extraordinary expenditures for significant infrastructure investments that further state policy objectives. Rate riders use cost trackers that are subject to a focused review of proposed investments and forecasted and actual expenditures – and may include other cost containment features, such as cost caps, which is the case with our Transmission Cost Recovery (TCR) rider, or incentives – this was the case with our Metro Emissions Reduction Project (MERP).

The Company has consistently taken the position that performance metrics can be useful tools in supporting public policy goals and driving utility performance but should be viewed within the context of the broader revenue and business model. Alternative regulatory approaches like PBR should encourage innovation and flexibility, while balancing reward with risk. It is important to note that, the State of Minnesota's regulatory framework is already strong with multiple statutes and other requirements currently requiring utilities to report on many aspects of their performance, including Minn. R. 7826 (service quality), Minn. R. 7820 (other utility service responsibilities), and Minn. Stat. § 216B.241 (Energy Conservation and Optimization (ECO), formerly known as the Conservation Improvement Program (CIP).

Parties involved in this proceeding have engaged in an extensive regulatory and stakeholder process that began in 2015 and continues today. The Commission's January 8, 2019 Order in this docket has laid a foundation and established a: (1) Performance Incentive Mechanism (PIM) Process, (2) and set Goals, (3) Outcomes, and (4) Metric Design Principles. That foundation is provided next.

1) Approved PIM Process: The current PBR PIM process has completed steps one through four. With this *Notice*, the Commission may seek to move to steps five and six: establishing targets and incentives as needed.



2) The approved Goals include:

In overseeing the rates, investments, and returns made by the investor-owned utilities in Minnesota are to promote the public interest by ensuring environmental protection; adequate efficient, and reasonable service; reasonable rates; and the opportunity for regulated entities to receive a fair and reasonable return on their investment.

3) The five approved Outcomes (related to three categories: customer focus, utility performance, and public policy) are:

   1. *Affordability;*
   2. *Reliability, including both customer and system-wide perspectives;*
   3. *Customer service quality, including satisfaction, engagement and empowerment;*
   4. *Environmental performance, including carbon reductions and beneficial electrification; and*
   5. *Cost effective alignment of generation and load, including demand response.*

4) The approved Metric Design Principles are as follows:

- *<u>Tied to the policy goal</u>. A metric should clearly reflect whether or not the underlying policy goal is being met. That is, it should seek and evaluate data that is specifically tied to the particular policy goal underlying the metric.*

- *Clearly defined.* *The method of calculating a metric should be precise and unambiguous to enable meaningful comparisons and to reduce potential disputes.*

- *Able to be quantified using reasonably available data.* *Using already reported data or data that is readily available will reduce administrative burden and the costs associated with implementing the metric.*

- *Sufficiently objective and free from external influences.* *Metrics should seek to measure behaviors that are within a utility's control and free from exogenous influences, such as weather or market forces.*

- *Easily interpreted.* *Metrics should exclude the effects of factors outside a utility's control so they provide a better understanding of utility performance and should use measurement units that facilitate comparisons across time and utilities (i.e., "per kWh" or "per customer").*

- *Easily verified.* *Straight-forward data collection and analysis techniques should be used, and independent third-party evaluators can further ensure accurate verification with respect to performance metrics.*

- *Should complement and inform evaluation of utility performance.* *Performance metric systems should be designed to complement – not replace – other parts of a utility's regulatory system such as multi-year rate plans and cost trackers.*

The Commission has approved 34 metrics in five approved Outcomes, including: four in Affordability, eight in Reliability, four in Customer Service Quality, 11 in Environmental Performance [Metric 5 in this Outcome has three distinct metric reporting requirements], and seven in Cost Effective Alignment of Generation and Load [Metric 4 in this Outcome has three distinct metric reporting requirements]. Additionally, the Company is required to report on our Workforce Transition Plan, and Dashboard Development Discussions.

COMMENTS

Following the established PIM process, the Company has given careful consideration to the next phase of this proceeding, moving to steps five and six. In response to the *Notice*, we offer insight from other subject matter experts as well as recommended benchmarks, and future targets and PIM methodologies for further discussion in our Comments.

We appreciate the two-week extension to frame our responses to the topics opened for Comment and discuss them below. Additionally, we were able to use the time to confer with many of the stakeholders most engaged in the original proceeding. These included the Department of Commerce, Citizens Utility Board, Vote Solar, Environmental Law and Policy Center, Fresh Energy, the Center for Energy and the Environment, the Office of Attorney General, and City of Minneapolis. During these conversations, there seemed to be an acknowledgement that recently passed Federal and State Legislation could have significant impacts on many of the metrics involved in this proceeding and how it moves forward. When the stakeholder process began developing the metrics in this docket in 2017–2019, more recent State Legislation like the 100% Carbon Free Electricity Standard by 2040, the 2030 Distributed Solar Energy Standard, the Natural Gas Innovation Act (NGIA), and the Environment, Natural Resources, Energy, and Climate Omnibus Bill (ECO Act), were not within our scope.

The Commission and utilities are in the early stages of planning for the implementation of these changes and should be given time to consider their impact on this docket prior to moving forward.[5] Additionally, newly passed Federal Legislation like the Infrastructure, Investment, and Jobs Act (IIJA) and the Inflation Reduction Act (IRA) provide substantial incentives for developing green energy, and new technologies to drive innovation, and customer savings as we work to reduce carbon emissions.[6] The Environmental Protection Agency has recently proposed Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants[7] and finalized a Good Neighbor Plan, which will regulate NOx emissions from power plants in states including Minnesota.[8] We do believe the significant work done by stakeholders to date continues to lay the foundation for the PBR process. However, due to the many new laws passed that do not yet have established standards or processes, it would be prudent to take some time and fully assess the new landscape, including which metrics could be impacted by which new legislation and determine effective timelines, where possible, prior to moving forward with a comprehensive plan to establish targets and PIMs.

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[5] The Commission recently initiated an investigation into Minnesota's Carbon Free Standard will result in "Orders necessary for utilities to comply with" the Renewable Energy Standard, Solar Energy Standard, and Carbon Free Standard (see Docket No. E999/CI-23-151, NOTICE OF DOCKET PROCESS AND TIMELINE, July 7, 2023).

[6] IIJA -- Infrastructure Investment and Jobs Act of 1921, Pub. L. No. 117-58, 135 Stat. 42 (2021); IRA -- Inflation Reduction Act of 2022, Pub. L. No. 117-169, 136 Stat. 1818 (2022).

[7] Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants | US EPAhttps://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power

[8] Good Neighbor Plan for 2015 Ozone NAAQS | US EPA

We believe it is important that the Commission consider what it would like the PBR process to ultimately accomplish at this point in the proceeding. The original approved PBR goal is referenced above, but since that time, there have been discussions of metrics, targets, and PIMs in multiple dockets. Does the Commission want to use this proceeding to report on multiple metrics – even those without targets and/or PIMs associated with them? If that is the case, is it efficient to report the same or similar data in multiple places? For example, we report our reliability metrics in our annual service quality dockets, this PBR annual report, and SAIDI, SAIFI, CEMI, and CELI are reported annually and have underperformance penalties associated with them within our service quality tariff. Demand Response SHED actual results are reported annually in multiple dockets including E002/M-20-421, E002/CI-01-1024, and E002/M-01-46. Residential Customer Disconnections are reported in six distinct dockets and discussed further below. We believe there is value in providing a comprehensive view of metrics, targets, and PIMs. However, consideration should be given to redundant reporting in an effort to compile all metrics, targets, and PIMs into one place. While we have responded to the request for baselines in this *Notice,* if and when the Commission decides to move forward in this proceeding, we recommend a focused approach and that only metrics with targets and or PIMs should be reported within this docket.

Additionally, established metrics currently reported annually in our Service Quality Tariff filing indicating performance relative to approved thresholds with underperformance penalties and our annual Conservation Improvement Program (CIP) – performance incentive mechanism under ECO, should remain within their respective reporting structures.

We provide an updated Attachment A that includes baselines, references, and targets where appropriate in columns L-N.

I. Accepting Annual Reports & Meeting Requirements

1. *Should the Commission accept Xcel's 2021 & 2022 PBR Annual Reports? Do Xcel's reports address the requirements set forth by Commission Orders in this docket, including but not limited to:*
   - *Future metrics?*
   - *Development of an online utility performance dashboard?*
   - *Data collection on and/or reductions in upstream methane emissions?*

Accepting our 2021 & 2022 PBR Annual Reports

We believe we have met all the compliance requirements within the Commission Orders issued in this docket. For that reason, we ask the Commission to approve both our 2021 and 2022 PBR Annual Reports.

Future Metrics

Power Quality & $MAIFI_E$

The future metrics of Power Quality and Momentary Average Interruption Frequency Index ($MAIFI_E$) utilize meter data, which is tied to the complete and successful deployment of the Advanced Metering Infrastructure (AMI). In our 2022 PBR Annual Report, we continued to update our AMI deployment schedule and recommend a process to move forward.

We currently anticipate AMI deployment will be complete in 2025. As a result, we will propose calculations and verification methodologies for these metrics once we have sufficient AMI meter capability data, likely in 2025. Tracking will begin in 2026 and reporting will begin in 2027.

Once the rollout of AMI is complete across the service territory, any necessary system or software implementations are completed, and there is one full year worth of data collected, then the Company plans to begin reporting $MAIFI_E$ utilizing the AMI technology.

The approved $MAIFI_E$ metric calculation is:

$$\frac{\text{Sum of Total Momentary Customer Interruptions}}{\text{Total Number of Customers Served}}$$

Similar to other reliability reporting, reporting of $MAIFI_E$ occurs with and without major event days. Momentary events are considered to have a duration of less than or equal to 5 minutes. It should be noted that while the Company does currently report on $MAIFI_E$ in our Service Quality Annual Reports, until AMI is fully deployed, the $MAIFI_E$ numbers will continue to reflect only the momentary data as reported via Supervisory Control and Data Acquisition (SCADA) systems. The use of AMI enables the Company to identify the occurrence of momentary interruptions at the customer's meter that were caused by overcurrent protective devices that do not provide automatic reporting to the Outage Management System (OMS).

Online Dashboard/Scorecard

In its April 16, 2020 Order, Order Point 1(e), the Commission directed the Company to:

> *Work in direct consultation with interested stakeholders, explore and develop options to employ an online utility performance dashboard and present those options to the Commission in the first annual report, including a fair discussion of the costs involved.*

In March of 2021, the Company issued a Notice of Stakeholder Discussion in accordance with the Order. Several stakeholders attended the discussion including: the Department of Commerce, the Office of the Attorney General, Minnesota Public Utilities Commission, Stoel Rives, The Mendota Group, Center for Energy & the Environment, and the Suburban Rate Authority. At this meeting, parties reviewed current scorecard options that ranged from regulator managed to utility managed, and these broadly varied in how the data was presented. A significant portion of the discussion at this meeting focused on cost to produce and maintain the dashboard, balanced with who would utilize the dashboard and to what extent. Ultimately, the group determined that not all metrics needed to be included on the dashboard, rather, only the most critical should be displayed. The group requested to view an illustration.

The Commission issued a February 9, 2022 Order directing the Company to:

> *Host one or more stakeholder meetings for stakeholders to ask questions and provide feedback on the proposed scorecard.*

On February 7, 2022, the Company issued a Notice of Stakeholder Meeting, and a stakeholder discussion was held to address this compliance point on February 22, 2022. Stakeholders attending this meeting included: Center for Energy & Environment, Department of Commerce, and The Mendota Group.

The discussion began with a review of where the stakeholder group landed at our last meeting on March 2, 2021, which created the framework for the scorecard the Company submitted in our 2020 PBR Annual Report. In that discussion, the stakeholder group thought it would be valuable to develop an illustration in order to visualize an online scorecard and to help frame the context, necessity and usability of such a tool for Commission review. The illustration depicts the Commission's approved five Outcomes: Affordability, Reliability, Customer Service Quality, Environmental Performance, and Cost-Effective Alignment of Generation and Load.

In our 2021 Annual Report with 2020 data, we included a proposed scorecard that aligned with the discussions we had with the stakeholder group, utilizing the smaller subset that we believe parties may be most interested in, including:

- Average monthly bills for residential customers,
- SAIDI,
- Number of Customer Complaints,
- Total carbon emissions by (1) utility-owned facilities and PPAs and (2) all sources, and
- Demand response, including (1) capacity available (MW & MWh).

As the scorecard is for illustrative purposes, we provided five years of data. The 2021 Annual Report scorecard is shown below.

Xcel Energy

Performance Metrics Scorecard
April 30, 2021

Category	Metric	Previous Year Trend	2020	2019	2018	2017	2016
Affordability	Average Residential Bill	↑	$88.28	$83.74	$91.30	$84.75	$83.73
Reliability	SAIDI	↑	All Days: 134.19 Normalized: 98.92	All Days: 124.50 Normalized: 81.02	All Days: 125.00 Normalized: 96.07	All Days: 141.70 Normalized: 57.04	All Days: 214.39 Normalized: 90.45
Customer Service Quality	Customer Complaints	↓	.1341 per 1000 Customers	.2244 per 1000 Customers	.1417 per 1000 Customers	.0651 per 1000 Customers	.0571 per 1000 Customers
Environmental Performance	Total Carbon Emissions	↓	12,801,300 tons	16,229,466 tons	18,549,479 tons	18,891,471 tons	18,972,617 tons
Cost Effective Alignment of Generation and Load	Demand Response	↔	Total Capacity: 754.6 MW 155,967 MWh	Total Capacity: 737 MW 164,716 MWh	Total Capacity: 731 MW 155,645 MWh	Total Capacity: 658 MW 134,140 MWh	Total Capacity: 723 MW 134,550 MWh

Stakeholder Group Recommendations

The stakeholder group, by consensus, agreed it was premature to develop a scorecard at that time. Aligning with the Commission's February 9, Order[9] to collect data for three years prior to developing evaluation criteria and benchmarking targets, the group determined it is preferable to postpone creating a scorecard until after establishing the evaluation criteria benchmarking targets, invest in the development of a scorecard for

[9] Order Accepting Report and Setting Additional Requirements; Docket No. E002/CI-17-401; February 9, 2022.

one set of metrics, then recreate a new one if a different set of metrics is determined to be more valuable to the end user. Additionally, if the Commission determines a scorecard should be developed in the future, the group agreed costs should be considered and a stationary image, such as the illustration above, updated once annually and hosted on Xcel Energy's website was recommended.

If the Commission decides to further explore scorecard development at this time, cost estimates associated with the creation and maintenance of a dashboard will need to be updated. To provide more refined estimates, the Company asks for direction on what the scorecard should include. There are significant price differences between creating automated processes with multiple metrics versus a more manual, stationary dashboard of select metrics, updated annually, as the workgroup generally recommended.

Upstream Methane Emissions

The Company's qualitative reporting of Environmental Performance Metrics 8 and 9 for informational purposes is adequate and we support continued reporting on upstream methane emission reductions as it aligns with our focus on improving methane emission reporting from gas production but recommend moving the discussion to reporting associated with the Gas Integrated Resource Plan (IRP). As discussed in our 2022 Annual Report submitted in April 2023, upstream methane emissions data specific to NSP Minnesota's gas suppliers is not available at this time. Gas purchasing is not direct from gas producers at the wellhead but rather from market centers that are aggregating gas supply from multiple sources.

Currently, we do not have a means to determine the source of each quantity of purchased gas with certainty; suppliers may change daily, and there is no contractual or legal obligation for the seller to provide methane emissions data. Additionally, emissions from upstream and midstream operations are outside of the Company's control as they occur before we receive gas. Nonetheless, the Company is committed to reducing methane emissions throughout the natural gas supply chain and working to influence gas producers and suppliers to reduce these upstream and midstream emissions, as well as to improve disclosures of emission data. We have described those efforts in our 2022 Annual Report, including support for the U.S. Environmental Protection Agency's direct regulation of methane emissions from the upstream oil and gas sector, our steps toward purchasing natural gas certified to have a low methane content, and participation in voluntary initiatives to quantify methane from gas suppliers and to reduce upstream emissions. We support continued reporting on upstream methane emission reductions as it aligns with our focus on improving methane emission reporting from gas production.

II. Metric Baseline Development

2. *From the three years of data that have been filed for each metric, how should a single baseline value be calculated? Please explain your reasoning and provide calculations of the baseline for each metric.*

Baseline development must continue to follow the established and Commission approved PBR Goals and Metric Design Principles outlined above. When developing baseline values for metrics, consideration must be given to how each baseline will stand the test of time, including customer growth and policy changes. By comparison, in the State of Illinois, Ameren Illinois Company determined baselines differently for many of their eight different metrics.[10] However, most baselines were set utilizing a three-year average. Commonwealth Edison in Illinois used a bit broader timeframe for their baseline setting[11].

Generally, utilizing a rolling three years of filed data for each metric provides the necessary historical data to inform baseline setting and target development setting as we move into steps five and six of the PIM process. Baseline values will differ by the metrics themselves and the standard they can be compared to may require a different baseline methodology for some.

Additionally, many of the approved environmental performance metrics already have an established future target year, and an annual baseline is not appropriate as they may contain elements outside the utility's control, such as legislative and regulatory process or global supply chain issues.

For each approved metric, we provide an updated Attachment A to our most recent filed Annual Report that lists a proposed or a current approved baseline shown in columns L and M.[12] Note, a baseline is not appropriate for some metrics and reasons why are explained in column M.

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[10] https://icc.illinois.gov/docket/P2022-0063/documents/319567#:~:text=Ameren%20Illinois%20Company%20d/b/a%20Ameren%20Illinois%20Petition%20for%20Approval%20of%20Performance%20and%20Tracking%20Metrics%20pursuant%20to%20220%20ILCS%205/16%2D108.18(e)

[11] https://www.icc.illinois.gov/downloads/public/en/ComEd%20Performance%20Metrics%20-%2010-year%20Plan.pdf

[12] 2022 Annual Report, Performance Metrics and Incentives, Filed April 28, 2023 in Docket No. E002/CI-17-401.

III. Setting Targets on Metrics

3. *For which metrics, if any, should the Commission set targets and why?*

If the Commission determines this is the appropriate time in the PBR proceeding to set targets and move into Step 5 of the PIM process, which is target setting, a common understanding of how they should be used and designed will guide this development. Additionally, a target should not be set for any metric that does not have sufficient baseline data available. In *Utility Performance Incentive Mechanisms: A Handbook for Regulators*[13] (Handbook) developed by Synapse Energy Economics, Inc, they provide insight into target setting that is based on a foundation very similar to the current Commission adopted PIM process and metric design principles.

In its Handbook, Synapse states that, "A performance target defines the precise level of service that a utility is expected to achieve during a particular time period. Targets may be used simply to provide guidance for a utility, with neither a penalty nor reward attached. Performance targets can also be used as the basis for providing a utility with a financial incentive to achieve desired outcomes."

IV. Target Methodologies

4. *Where applicable, by what methodology should targets be set? How often should targets be reviewed and potentially updated?*

Synapses' Handbook recommends the following Design Principles be considered when setting performance targets:

1. Tie targets to regulatory policy goals
2. Balance costs and benefits
3. Set realistic targets
4. Incorporate stakeholder input
5. Use deadbands to mitigate uncertainty and variability
6. Use time intervals that allow for long-term, sustainable solutions
7. Allow targets to evolve

The Handbook also recommends tying the target to the ultimate policy goal. It states, "Consider what level of performance is necessary to achieve policy goals, and state this

[13] Synapse Energy Economics, Inc.Utility Performance Mechanisms; A Handbook for Regulators, Prepared for the Western Interstate Energy Board, March 9, 2015 [p34-40]

explicitly. Doing so will help stakeholders evaluate whether performance targets are being set in a manner that moves toward achieving these policy goals and will help maintain momentum in that direction, while also allowing stakeholders to better determine when the underlying policy objective—as opposed to simply meeting the target—has been achieved."

Further, the Handbook recommends to balance costs and benefits, stating, "Balance the costs to customers of achieving the target with the benefits to customers. Ratepayer surveys can help to identify ratepayers' priorities and how much they are willing to pay for higher levels of utility performance… In theory, the optimal level of performance is obtained where the marginal benefits from improved performance are equal to the marginal costs of providing that increased level of performance. As explained by Baldwin and Cave, ['as quality increases it becomes more expensive to raise it further; hence the marginal cost of quality improvement rises as quality rises. In contrast, as quality rises, the extra benefit consumers get from a further increase in quality declines. These two factors determine an optimal level of quality, where marginal benefit (to the customer) and marginal cost (to the utility company) are equal'] (Baldwin and Cave 1999, 253)."

The National Association of Regulatory Utility Commissioners (NARUC) provides information on Performance Based Ratemaking, including a series of webinars on metric to target to PIM development as well as a state tracker. The state tracker includes links to view the recent status of different utilities and was last updated in April of this year[14]. In reviewing the NARUC State and utility information, it is clear that States vary in how they have approved PBR, basing it on their own priorities. Minnesota's PBR process has been long and deliberate. We are fortunate to not have significant reliability concerns or top tier customer costs creating the need for an immediate correction. We also have long established electric and gas Service Reliability and Service Quality Plans we report on annually that provide for regular regulatory review, and for seven targets, an under-performance penalty for not meeting the agreed upon performance levels.

Target development should include considerations such as peer benchmarking and PIM experience, a utilities historical performance, federal and statewide goals and policies, and Commission Orders. For example, there may be times when it is appropriate to adjust or change a baseline or calculation methodology. This helps

[14] https://naruc.org/cpi-1/energy-distribution/valuation-and-ratemaking/performance-based-regulation/

account for the impacts from system investments that are expected to decrease outage frequency, outage duration, or some other aspect of our service to customers, or not receiving regulatory approval for the necessary capital investment that would make it possible to achieve targets.

To mitigate uncertainty and variability, most targets should include a symmetrical dead band around the baseline, whereby increments of standard deviations may determine the Company's treatment. For example, this methodology may consider a neutral zone or "dead band" of one standard deviation from the target baseline with no penalty or reward. However, two standard deviations from the target baseline will trigger either a penalty or reward. The Commission also indicated its support for the neutral zone approach in the Transmission Cost Recovery Rider proceeding (Docket No. E002/M-21-814). The Commission's June 28, 2023 Order, Order Pt. 16(e)(ii) in that docket states that the Company must consider "Hawaii's approach with use of penalties and incentives for performance at certain thresholds and a 'deadband,' a neutral zone around the target for acceptable performance with no attached penalty or incentive" when proposing incentive values for PIMs associated with Advanced Meter Infrastructure (AMI) and Field Area Network (FAN) investments. Other metrics may not be appropriate for a deadband and standard deviation treatment.

Generally, we believe targets should be set with a long-term goal in mind. The Company does not believe a continuous movement of targets and PIMs is either reasonable or practicable if targets are established to meet a performance need and will require planning and capital investment, or as we look to further establish systems and processes to meet them. Consistent with the Metric Design Principles approved by the Commission, circumstances out of our control that affect our ability to respond to targets should be eligible for an exception for a period of time until the metric is fully within our control again. For example, our Meter Equipment Malfunctions tariff sets meter performance measures, billing adjustment parameters, and exclusions for items outside of our control including periods of emergency or equipment issues.[15] We also recognize the importance of ensuring targets are reviewed at regular intervals and for that reason, we continue to support a review every three years. If targets for existing metrics can be established at intervals in between and are consistent with new Federal and State Legislation, we propose to address them in our annual reports.

[15] Northern States Power Company, Minnesota Electric Rate Book – MPUC NO.2, General Rules and Regulations, Section 6, Sheet Nos 17.2-17.4.

V. Appropriate Target Levels

5. Where applicable, what are appropriate targets for the metrics?

The Company has established targets and associated underperformance penalties for seven of the 34 current metrics we report on. These targets and underperformance penalties are noted in Attachment A and include Reliability Outcome (1) SAIDI, (2) SAIFI, (3) CEMI, (4) CELI, Customer Service Quality Outcome (5) Call Center Response Time, (6) Billing Invoice Accuracy, (7) Number of Customer Complaints. No additional underperformance penalties should be assessed on these targets, and they should remain in the existing and approved service quality tariff docket filed each April.

Proposed Targets

As stated earlier, newly passed federal and state legislation will guide how some of the targets should be developed and warrant a comprehensive review as processes and standards are developed to implement the new Legislation. Additionally, the COVID pandemic and AMI implementation provides for inconsistent customer disconnection data until AMI is fully deployed.

One fairly common theme in other states PBR initiatives, is the desire to include an equity component. The Commission has also expressed its interest in equity in various dockets and at hearings. We believe there is opportunity to incorporate a future equity-based metric within the Affordability Outcome measuring reduced customer disconnections, utilizing our existing interactive map within the Service Reliability and Service Quality docket.

a) Affordability (Metric 3) – Decreasing Customer Disconnections in Identified Areas of Concentrated Poverty

The Company reports extensively on affordability-related metrics across various dockets, and we will soon have baselines and targets set – albeit outside the PBR process – for cost savings metrics related to disconnections within the TCR proceeding. However, we believe there may be value in setting a future target focused on reduced customer disconnections in geographical areas identified by our Electric Service Quality map utilizing census block groups to help those most in need when an appropriate baseline of data becomes available.

Somewhat similar to our proposal to wait on establishing targets until such time as new critical federal and state legislation has established procedures and/or standards to utilize in our own target development, this equity-based disconnection metric requires an appropriate baseline. Two baseline challenges make this target inappropriate to set at this time. First, the COVID pandemic included disconnection moratoriums in 2020, 2021, and part of 2022, creating an unrepresentative recent data history. Second, we have begun AMI implementation with a planned rollout completion in 2025. As discussed in the remote disconnect/reconnect proceeding, we expect a peak in the volume of disconnections to coincide with full deployment of AMI meters to occur in 2025 and into 2026, past the end of the 2026 CWR period. We estimate that 1.2 percent of our customer base could experience disconnections each month (during non-Cold Weather Rule months) at this initial peak. Using Salt River Project as a benchmark, after this peak, we anticipate up to a 25 percent reduction in the volume of customers experiencing a disconnection as behavior adjusts and customers understand it is important they reach out to us for help with their bills prior to disconnection. Using the Salt River Project as a guide, this has been shown to improve customer interactions, bring more resources to customers, and ultimately reduce their past due balances.[16]

The future Affordability Outcome target we propose for our Residential Customer Disconnection metric utilizes a baseline of customer disconnections (yet to be determined following AMI deployment) and a decrease in the percent of actual customer disconnections per 1,000 customers disconnected in the identified equity-based census block groups.

To achieve this target, the Company will utilize the existing Electric Service Quality Interactive Map[17] to identify census block groups at or below 185% of Federal Poverty Level that show the lowest affordability program participation and greatest disconnection rates, hence the largest potential for help. We provide a map for illustrative purposes. See Figure 1 below. Similar to Ameren's approach, the Company intends to apply focused outreach efforts in the identified census block groups, such as working through community-based organizations to provide more in person outreach at public events where we help customers apply for LIHEAP on site. Utilizing the map to identify areas with the greatest need also provides us with the tools to efficiently deploy resources. We will monitor each of these efforts for efficacy. We will also monitor the 'last phone calls' or 'door knocks' made to customers who have received the disconnection notice, prior to actual disconnection and adjust the times where possible for the greatest effectiveness in an effort to reach our customers when they are best able to receive it.

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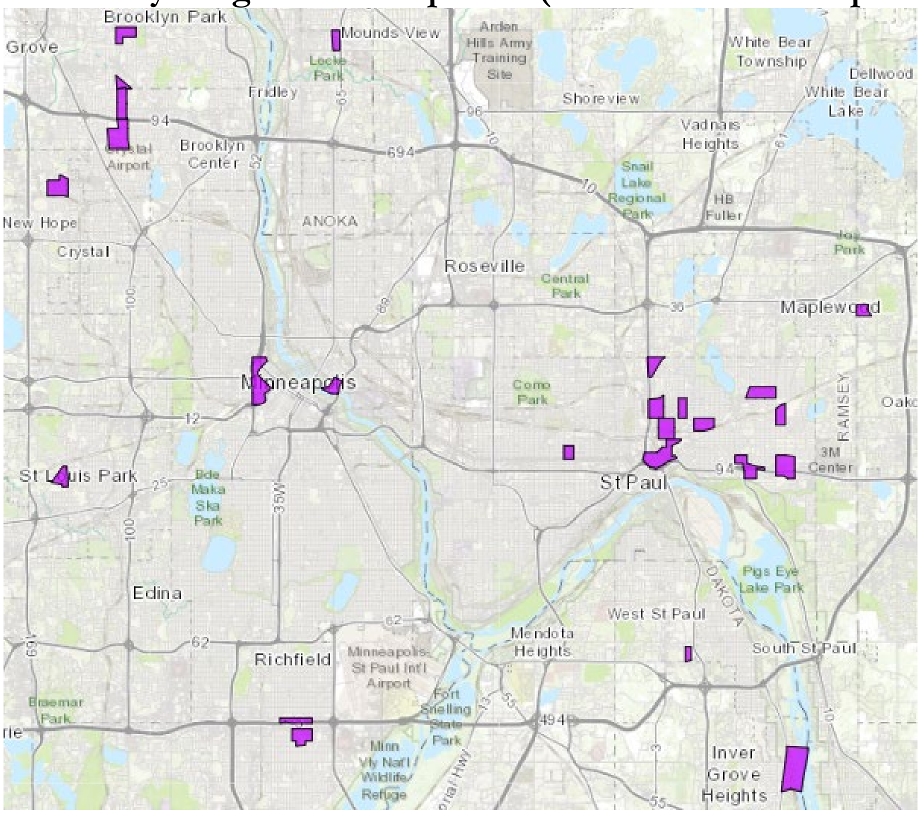
[16] *See* Attachment A to our April 14, 2022 Petition in Docket No. E002/M-22-233.

[17] Xcel Energy MN Electric Service Quality Interactive Map (arcgis.com)

Figure 1:
Identified Census Block Groups with Highest Disconnect Rates and Lowest Affordability Program Participation (For Illustrative Purposes)



When this metric has appropriate baseline data to set a target, likely in 2027, we will propose between 20-25 specific census block groups to apply the target to in our annual report. Until that time, the Company will continue to report on disconnection rates in this docket, the weekly and monthly Residential Status Reports, program influences and efforts in the Annual Low-Income Discount and Gas Affordability Plan filings, more extensively on our overall efforts in the annual Service Reliability and Service Quality filing, and reduced cost impacts of remote disconnect/reconnect in the Transmission Cost Recovery Rider.

Ameren Illinois has a similar target in which they focus on reducing aggregate disconnections in identified zip codes. Specifically, their metric aims to "Achieve affordable customer delivery service costs, with particular emphasis on keeping the bills of lower-income households, households in equity investment eligible communities, and household in environmental justice communities within a manageable portion of their income and adopting credit and collection policies that reduce disconnections for these households specifically and for customers overall to ensure equitable disconnections, late fees, or arrearages as a result of utility credit and collection practices, which may include consideration of impact by zip code. This metric is intended to help residential customers by assisting them in avoiding disconnection through proactive measures and not merely allowing arrearages to increase. While the metric measures the aggregate disconnections in the 20 zip codes, it is not the intent to simply focus on zip codes with higher levels of disconnections…. The Company intends to achieve decreases in disconnections in those zip codes through proactive measures and intends to explore creative solutions and monitor their efficacy. Because disconnections for nonpayment result in an expense to all customers (operational expenses and uncollectible expense), reducing the overall incidence of disconnection would, all else being equal, result in an overall reduction of residential customer delivery service costs and promote the affordability of those costs[18]".

Additional Customer Disconnection Related Target and Reporting Requirements

There are several places we are currently required to report on multiple aspects associated with customer disconnection data, or new Commission Orders require us to establish metrics, evaluation processes, and target development. We include these below for reference in this discussion.

i. As required by the Commission's June 28, 2023 Order in Docket No. E002/M-21-814 (the Transmission Cost Recovery [TCR] Rider Order), we will be tracking and reporting the below metrics related to service disconnections. Further, The TCR Order requires a compliance filing, due by August 27, 2023, in which we will put forward baselines and targets for these metrics (among others):
    - Reduced field and meter O&M expenses from remote disconnection,
    - Reduced consumption on inactive meters, and
    - Reduced bad debt expense.

ii. In addition, the Commission's March 22, 2023 Order approving the Company's use of remote disconnection and reconnection requires the Company to provide evaluation metrics in its 2023, 2024, and 2025 service quality reports, including (but not limited to):[19]
    - The percentage of customers flagged for disconnection who pay their disconnection amount in full in the [field visit] process versus after the variance [allowing for remote disconnection] has been implemented.
    - The number of field visits required when the Company is unable to reach the customer (speaking to the customer or leaving a voicemail).

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[18] Ameren Illinois Company Performance and Tracking Metrics Manual, Filed Pursuant to the Final Order on Rehearing April 5, 2023 in Docket No. ICC 33-0063.
[19] Docket No. E002/M-22-233. March 22, 2023 Order at Order Point 5.

- The length of time for reconnecting each customer, and the method for reconnecting the customer.

iii. Our Disconnections are also reported in our monthly Residential Customer Status Reports as well as our Low Income Discount Program Annual Report. The Residential Customer Status Reports, currently under Docket No. 23-02 include required reporting for both electric and gas customers:
   - # of residential customers receiving disconnect notices
   - # of residential customers involuntarily disconnected
   - # of residential customers restored to service within 24 hours
   - # of residential customers restored to service by entering into a payment plan
   - # of residential customers restored at the same address
   - Total # residential customers reconnected
   - # residential customers remaining disconnected 1-30 days
   - # residential customers remaining disconnected 31-60 days
   - # residential customers remaining disconnected 60+ days
   - # of customers disconnected who sought Cold Weather Rule protection (heat affected)
   - # of customers disconnected who sought Cold Weather Rule protection (non-heat affected)

iv. The Low Income Discount Program Annual Report under Docket Nos. E002/M-04-1956 AND E002/M-10-854 requires the following disconnection reporting:
   - Low Income Discount Program
     - Disconnection rates for Discount Program participants
     - Disconnection rates for non-Discount Program LIHEAP customers
   - PowerOn Program
     - Disconnection rates for PowerOn Program participants
     - Disconnection rates for non-PowerOn Program LIHEAP customers
   - Medical Affordability Program
     - Disconnection rates for Medical Affordability Program participants
     - Disconnection rates for non-Medical Affordability Program LIHEAP customers

v. The Gas Affordability Program (GAP) Annual Report under current Docket Nos. G002/GR-06-1429, G002/M-16-493, and G002/M-23-82.

- Percentage Disconnected (Non-GAP LIHEAP Baseline Approach)
    - Disconnection percentages for GAP participants
    - LIHEAP recipients that do not participate in GAP
    - All residential natural gas customers (non-GAP, non-LIHEAP)

b) Environmental Performance (Metrics 1[2] and 6)– Decreasing Emissions From "All Sources"

The Company recommends two future targets be established under the Environmental Performance Outcome. Those two Targets include Metric 1(2) - Total mass emissions from "all sources" associated with the electricity delivered to customers on an equity-share basis (owned facilities + purchased power – market sales) as this environmental performance metric most accurately represents carbon associated with retail sales to customers, and Metric (6) - Emissions avoided by building and other sector electrification.

As evidenced by the Minnesota Legislature passing House File 7, Second Engrossment, establishing a requirement that all utilities meet 100 percent of their Minnesota retail sales with carbon-free electricity by 2040, environmental policies are critically important to the State of Minnesota. We, as a Company, have stated many times our own goals to be a leader in the clean energy transition and expect our future resource plans to meet – and likely exceed – the requirements outlined. For this reason, we believe it is appropriate to set targets for exceeding the requirements of the new law because our additional contribution will help the State of Minnesota to reach its overarching climate goals and likely support emissions reductions for others (through increased clean energy sales to MISO and beneficial electrification).

Total Mass Emission Reductions from "All Sources" – Metric 1(2)

The first future target the Company recommends aligning Metric 1(2) CO2 mass emissions baseline and target setting. We believe baselines can be determined utilizing our most recent Integrated Resource Plan (IRP), and targets should be consistent with standards yet to be established with the State of Minnesota's carbon-free electricity standard requirements. In reviewing the Department's early filed Comments in this docket, they appear to agree on aligning the baseline with our IRP.

CO2 emissions avoided by electrification of buildings and other sectors - Metric 6

The Company recommends a second future target for beneficial electrification. As discussed in our 2022 Annual Report filed in April 2023, the Company currently has negligible building electrification to report. Further, frameworks have been adopted but not all details finalized for measuring GHG accounting. Assuming implementation of new supporting policy at the state and federal level proceeds timely, we may be able to assess and propose a target to include with the 2024 Annual Report, filed in 2025. The Company would likely propose an initial baseline of zero electrification unless adoption significantly increases in the next year as there has been negligible electrification to report prior to new policies aimed at increasing adoption and supporting markets.

Statutory changes in 2021, such as the Energy Conservation and Optimization (ECO) Act enabling "efficient fuel-switching" as part of the Company's demand-side management efforts, as well as the Natural Gas Innovation Act (NGIA), may enable future electrification. In addition, Inflation Reduction Act (IRA) Home Energy Rebates which will be made available by the Department of Energy later this summer, will further enable the adoption of electrification technologies. While funding and administration of IRA rebates is not directed to utilities, we look forward to supporting the State Energy Office with implementation of these incentives along with additional funding set aside by the state legislation in 2023. We hope to maximize programs by allowing IRA or state funds to build on the foundation of existing utility incentives for weatherization, electric appliances and water heaters.

The Company is working on our first NGIA innovation plan, which will be filed later in 2023 and our first ECO Triennial Plan covering the period 2024 through 2026 was filed on June 29, 2023 in Docket No. E,G002/CIP-23-92. Notably, ECO and NGIA required frameworks for greenhouse gas (GHG) accounting. Adopted frameworks provided necessary structure but left some details to be finalized with submittal of our first plans. Calculation methods for Metric 6 may need to be adjusted to align with the GHG accounting approaches ultimately adopted.

c) Reliability (Metrics 1 & 2) – Improving SAIDI and SAIFI

The PBR docket includes eight approved metrics under the Reliability Outcome. Four of those eight metrics included within our Service Quality Tariff: SAIDI, SAIFI, CEMI-6 and CELI-24[20] have existing targets and underperformance penalties. In the Service Quality Tariff structure, the SAIDI and SAIFI both have an upper performance target and penalty association. The Company believes there is room to implement an asymmetrical incentive structure to improve normalized SAIDI and SAIFI. We propose to balance the underperformance penalties of SAIDI and SAIFI,

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[20] 1 Minnesota Electric Rate Book, General Rules and Regulations (Section 6), Service Quality (Sheet Nos. 7.1-7.11).

with a reward target set at one six-year standard deviation below the three-year average for SAIDI and SAIFI. Under this structure, 84% of expected year-to-year natural variation with a normal distribution would not receive a reward.

Consistent with the other three target recommendations, we believe that the PBR process as a whole should take a step back and assess the metrics in relation to newly passed state and federal legislation in this docket prior to moving to Steps 5 and 6. For this reason, the Company is recommending waiting before moving forward with target and PIM development of this metric.

VI. Evaluation of Metrics Without an Established Baseline

6. *How should the Commission evaluate the metrics that do not yet have three years of baseline data?*

All current approved metrics have three years of baseline data, except those noted as "future metrics". If metrics are added to PBR reporting, the Company must have the ability to gather the historical information or if it is a newly developed metric, report the metric as approved with three years of data prior to establishing an appropriate target. As indicated, some metrics may provide the best performance insight by using industry benchmarking in conjunction with historical performance in target setting.

If a metric is approved with accessible existing three years of data, the Company will include that information in our next annual report. If a new metric is approved that the Company is unable to obtain three years of data to report the metric, the Commission should wait three years and follow the established process to determine a baseline or create a target (if appropriate).

VII. Necessary Action on the Workforce Transition Plan

7. *What action should the Commission take on reporting the Company's Workforce Transition plan in Docket No. E002/M-22-265 rather than the instant docket?*

There is significant overlap in reporting of the Workforce Transition Plan (Plan)in this docket and Docket No. E002/M-22-265, the Workforce Transition docket, which was opened on June 30, 2022 as required by the Commission's Order in our most recent Integrated Resource Plan (IRP).[21] We believe it is most efficient to report on the Plan in the Workforce Transition docket. The annual update requirements for the Plan are

[21] *See* Docket No. E002/RP-19-368, ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE FILINGS at Order Point 24 (April 15, 2022).

more robust in the Commission's IRP Order, as our reporting based on those requirements provides a comprehensive Plan of our ongoing work with plant employees and stakeholders during the clean energy transition. Pending Commission hearing on our 2022 (2021 data) and 2023 (2022 data) PBR Annual Reports requesting to transfer the duplicative Workforce Transition Plan reporting to the new, dedicated docket, we included a copy of each year's Workforce Transition Plan. Additionally, the Department's November 1, 2022 Letter in this docket recommended the Commission, via consent calendar, transfer workforce transition reporting to the Workforce Transition docket. If the Commission determines it is beneficial to continue to submit our Workforce Transition Plan in this docket, we will file our most recent comprehensive Plan filed annually at the end of December (four months previous) in the Workforce Transition docket, as there will be no comprehensive updates to provide between the two filing timelines.

VIII. Other Concerns for Consideration

8. *Target Discussions with Stakeholders*

Staff states in the Notice that "*Staff expects discussions on targets to have already begun, per the Commission's April 16, 2020 Order*". However, the Company wishes to clarify that it is our understanding from reading the rest of the paragraph in the referenced Order that we were to wait for the Commission to open this process prior to working with stakeholders on evaluation criteria and benchmarks. Specifically, the remaining portion of the paragraph reads, "*The Commission will wait until the appropriate step in the PIM process to decide on criteria for good versus bad performance and establish benchmarks against which to measure Xcel's performance; however, the process of evaluating such criteria and benchmarks is likely to be complex and time-consuming, and the Commission will direct Xcel and stakeholders to begin that process*[22]."

Additionally, we requested the Commission consider three years of annual report data (2021 through 2023 reports for 2020 through 2022 data) prior to developing the benchmarking criteria. We believe this provides an adequate timeframe to develop a record and for all parties to assess appropriate benchmarking criteria. This position was supported by most stakeholders, and the Commission approved the request in its February 9, 2022 Order:

> *[P]rovide three years of data before developing evaluation and benchmarking targets*

[22] In the Matter of a Commission Investigation to Identify Performance Metrics, and Potentially, Incentives for Xcel Energy's Electric Utility Operation; Order Establishing Methodologies and Reporting Schedules, Docket No. E002/CI-17-401, Section III Commission Action, p8

for the performance metrics.

That three-year reporting process concluded with our 2022 report, filed in April 2023. In each of the Company's 2022 (2021 data) and 2023 (2022 data) PBR Annual Reports, we indicated our willingness to engage in the next stage of evaluation and benchmarking criteria discussions when the Commission believed it was time to open the process to the next step. Both the 2022 and 2023 reports are currently pending hearing.

9. Assessing the Value of Metrics

The PBR process, as approved in the Commissioners January 8, 2019, established the PIM process, goals, outcomes and metric design principles. There may also be times where a metric or benchmark is no longer relevant – or a new metric or benchmark may be appropriate. However, because changes to these metrics must consider the specific circumstances of the changes to our grid and underlying systems, we believe the near-term focus for any new performance metrics should be on longer-term metrics that align with public policy objectives.

We believe there are two metrics at this time that do not meet the intent of the original reporting requirements and request removal of these metrics with supportive reasoning discussed for each below.

a. ACSI

In our 2023 PBR Annual Report, we requested the Commission consider removing two metrics from our reporting ASCI Customer Satisfaction Results, and the Load Factor for Load Net of Variable Renewable Generation because they did not prove to be useful in gaining additional insight on our performance as a utility. As is the intent of baseline data gathering, we utilized the three years of performance data under these metrics and are able to assess and make a determination of their value.

The first is under the Customer Service Quality Outcome; the American Customer Satisfaction Index (ACSI) that provides benchmarks by company for the largest investor-owned energy utilities serving residential customers. Our recommended customer satisfaction survey organization, J.D. Power has 145 large/midsize utilities in its residential electricity benchmark, while ACSI has 26 IOUs. However, during the Commission hearing in this proceeding, we agreed to provide the public facing survey results that can be found on the ACSI website[23] free of charge for Commission review.

[23] https://www.theacsi.org/industries/energy-utilities/investor-owned-energy-utilities/

The Company believes the ACSI should be re-considered and removed from reporting because it does not benchmark against as large of a peer utility group as our other customer satisfaction reporting with JD Power and provides no additional insight.

b. Load Net of Variable Renewable Generation

The second request for removal falls under the Cost Effective Alignment of Generation and Load Outcome and is the Load Factor for Load Net of Variable Renewable Generation. This metric was originally chosen as it is based on data of hourly generation by generation source that is currently tracked by the utility, and directly addresses the performance of aligning load through demand response to renewable generation sources. The metric reported for 2022 – 40.50% – is the annual load factor for load on the Company's generation system when load provided by renewable generation sources is excluded. This load factor includes the load from hydro generation, which is not considered renewable generation for this metric. This metric will allow us to incorporate the results of the previous demand response metrics as they continue to evolve. However, it also accounts for further impacts such as energy efficiency, which is measured through our Energy Conservation and Optimization Plan.

This metric has proven to be less effective than hoped in measuring the effectiveness of demand response efforts due to the rapid adoption of variable renewable generation. This is reflective of the percent of energy on the generation system from renewable energy, which has risen from 26.8% in 2020, to 30.8% in 2021 and 39.2% in 2022. The renewable energy adoption has greatly reduced the amount of energy in the load net of variable renewable generation. To produce a reduction in load factor, a dramatic reduction in peak load that may be beyond the potential of demand response is required.

CONCLUSION

Thank you for the opportunity to Comment on the development and implementation of baselines and targets within the PBR process. The Company believes there is value in taking some time to assess the impacts of the current metrics as they relate to newly passed Federal and State legislation prior to moving forward to steps 5 and 6 in the PIM process as those policy changes may have substantial impacts on target and PIM setting. We recommend reporting the approved metrics for another year under the current reporting structure and in the 2023 report – filed in 2024 - include an assessment of impacts of the current metrics and our current proposed targets and methodologies for the Commission to determine how it would like to proceed.

We request to move reporting of the methane emission information in the Environmental Performance Outcome Metrics seven through nine to either an NGIA or Natural Gas IRP dockets as well as the Workforce Transition Plan to the IRP docket opened specifically for that purpose.

We also request to discontinue reporting of the Customer Service Quality Outcome, metric one ACSI and Cost Effective Alignment of Generation and Load Outcome, and metric four (c), Load Net of Variable Renewable Generation.

We look forward to engaging throughout this proceeding.

Dated: July 31, 2023

Northern States Power Company

							METRICS TRACKING RESULTS AND EVALUATIONS					
OUTCOME	**COMMISSION-APPROVED METRIC**	**Reporting Status**	**APPROVED CALCULATION METHOD REPORT ANNUALLY**	**Proposed Baseline Calculation**	**Reference**	**Target**	**2022**	**2021**	**2020**	**2019**	**2018**	**2017**
Affordability												
1	Rates per kWh based on total revenue, reported (1) by customer class and (2) with all classes aggregated	Began in 2020 PBR Report	NSPM-MN customers only.	Electric Tariff Book	As approved by the PUC		• Residential: $0.15601/kWh • Commercial: $0.13256/kWh • Industrial: $0.10263/kWh • Total Customers: $13243/kWh	• Residential: $0.13921/kWh • Commercial: $0.11576/kWh • Industrial: $0.08996/kWh • Total Customers: $0.11689/kWh	• Residential: $0.13740/kWh • Commercial: $0.10494/kWh • Industrial: $0.07975/kWh • Total Customers: $0.10908/kWh	• Residential: $0.13625/kWh • Commercial: $0.10400/kWh • Industrial: $0.08023/kWh • Total Customers: $0.10724/kWh	• Residential: $0.14147/kWh • Commercial: $0.10549/kWh • Industrial: $0.08138/kWh • Total Customers: $0.10957/kWh	• Residential: $0.13786/kWh • Commercial: $0.10805/kWh • Industrial: $0.07839/kWh • Total Customers: $0.10840/kWh
2	Average monthly bills for residential customers	Began in 2020 PBR Report	Report annually: Total Annual Residential Class Revenue / Total Number of Residential Customers Served / 12 Months	Electric Tariff Book	As approved by the PUC		$98.62	$90.72	$88.28	$83.74	$91.30	$84.75
3	Total disconnections for nonpayment for residential customers	Reported Prior to PBR	Continue same system-generated process to determine total disconnections for nonpayment used in Quality Service Plan (QSP) reports, Cold Weather Rule, and Annual Electric Low Income Discount reporting. Process includes internal system-generated reporting of monthly disconnections on a Commission-approved template per Minn. Stat. § 216B.091.	NA	None at this time due to impacts of COVID moratoriums		9,263	6,062	2,819	14,939	16,218.00	17,777
4	Total arrearages for residential customers	Reported Prior to PBR	Continue same calculation process to determine total arrearages for reporting in Quality Service Plan (QSP) reports, Cold Weather Rule, and Annual Electric Low Income Discount reporting. Process includes internal system-generated reporting of monthly bad debt where arrears are calculated by company, customer type, active/inactive, number days overdue.	NA	None at this time due to impacts of COVID moratoriums		$88,482,147	$82,753,364	$60,838,363	$44,976,724	$44,895,753.00	$40,898,573.00
Reliability												
1	System Average Interruption Duration Index (SAIDI): Indicates average interruption duration per customer during defined period of time.	Reported Prior to PBR	Report with and without major event days. Sum of Total Sustained Customer Interruption Durations Total Number of Customers Served "Sustained event" = duration of more than 5 minutes **Order Point**: Direct Xcel to use a Normalization method consistent with the Commission's most recent Order in the Annual Service Quality, Safety, and reliability docket in reporting their SAIDI, SAIFI, CAIDI, CELID, and ASAI within this docket.	IEEE Second quartile performance for large utilities for Statewide, East and West Metro work centers, second quartile performance for medium utilities for Northwest and Southeast work centers, and less than 133.23 minutes with disincentive of $1.0 million annually for exceeding target	Approved by PUC Order	Underperformance Penalty in QSP Tariff; Annual Rules Normalized: 84.35 (incentive)	All Days: 184.42 Annual Rules Normalized: 90.00	All Days: 129.94 Annual Rules Normalized: 88.79	All Days: 134.19 Annual Rules Normalized: 98.92	All Days: 124.50 Annual Rules Normalized: 81.02	All Days: 125.00 Annual Rules Normalized: 96.07	All Days: 141.70 Annual Rules Normalized: 75.04
2	System Average Interruption Frequency Index (SAIFI): Indicates average number of sustained interruptions per customer over defined period of time.	Reported Prior to PBR	Use Jan–Dec each year to align with current reporting. Report with and without major event days. Proposed formula: Sum of Total Sustained Customers Interrupted Total Number of Customers Served **Order Point:** Direct Xcel to use a Normalization method consistent with the Commission's most recent Order in the Annual Service Quality, Safety, and reliability docket in reporting their SAIDI, SAIFI, CAIDI, CELID, and ASAI within this docket.	IEEE Second quartile performance for large utilities for Statewide, East and West Metro work centers, second quartile performance for medium utilities for Northwest and Southeast work centers, and less than or equal to 1.21 outage events with disincentive of $1.0 million annually for exceeding target	Approved by PUC Order	Underperformance Penalty in QSP Tariff; Annual Rules Normalized: 0.83 (incentive)	All Days: 1.08 Annual Rules Normalized: 0.86	All Days: 1.04 Annual Rules Normalized: 0.92	All Days: 1.07 Annual Rules Normalized: 0.99	All Days: 0.86 Annual Rules Normalized: 0.75	All Days: 0.95 Annual Rules Normalized: 0.89	All Days: 0.90 Annual Rules Normalized: 0.74
3	Customer Average Interruption Duration Index (CAIDI): Indicates average time to restore service to customers that have been interrupted from sustained event.	Reported Prior to PBR	Report with and without major event days. Proposed formula: Sum of Total Sustained Customer Interruption Durations Sum of Total Sustained Customers Interrupted **Order Point:** Direct Xcel to use a Normalization method consistent with the Commission's most recent Order in the Annual Service Quality, Safety, and reliability docket in reporting their SAIDI, SAIFI, CAIDI, CELID, and ASAI within this docket.	All Days: None proposed at this time. Annual Rules Normalized: 100.21	Annual Rules Normalized: Baseline set to the three-year average		All Days: 170.24 Annual Rules Normalized: 104.05	All Days: 124.67 Annual Rules Normalized: 96.31	All Days: 124.89 Annual Rules Normalized: 100.28	All Days: 145.30 Annual Rules Normalized: 108.29	All Days: 131.22 Annual Rules Normalized: 107.39	All Days: 158.10 Annual Rules Normalized: 100.90
4	Customers Experiencing Long Interruption Duration (CELID): Indicates ratio of customers experiencing interruptions with duration equal to or greater than "d" during defined period of time.	Reported Prior to PBR	Report with and without major event days. Proposed formula: Total Number of Customers that experienced interruptions of "d" or more hours duration Total Number of Customers Served Propose "d" = 24 hours. Consistent with annual Service Quality Plan, where customers experiencing outage of 24 hours or more receive $50 bill credit for each outage occurrence lasting longer than 24 hours. **Order Point:** Direct Xcel to use a Normalization method consistent with the Commission's most recent Order in the Annual Service Quality, Safety, and reliability docket in reporting their SAIDI, SAIFI, CAIDI, CELID, and ASAI within this docket.	For each interruption lasting more than 24 hours, customer receives $50 credit	Approved by PUC Order	Underperformance Penalty in QSP Tariff	All Days: 0.835% Annual Rules Normalized: 0.034% All Days CELID (12 Hours): 5.067% All CELID numbers include all levels & multiple CELID events to same premise	All Days 0.496% Annual Rules Normalized: 0.113% All Days CELID(12 Hours): 1.658% All CELID numbers include all levels & multiple CELID events to same premise	All Days: 0.339% Annual Rules Normalized: 0.133% All Days CELID(12 Hours): 2.660% All CELID numbers include all levels & multiple CELID events to same premise	All Days: 0.562% Annual Rules Normalized: 0.047%	All Days: 0.748% Annual Rules Normalized: 0.051 %	All Days: 1.030% Annual Rules Normalized: 0.078 %

OUTCOME	COMMISSION-APPROVED METRIC	Reporting Status	APPROVED CALCULATION METHOD REPORT ANNUALLY	Proposed Baseline Calculation	Reference	Target	2022	2021	2020	2019	2018	2017
5	Customers Experiencing Multiple Interruptions (CEMI): Indicates ratio of individual customers experiencing more than "n" sustained interruptions to total number of customers served.	Reported Prior to PBR	Report with and without major event days: Total Number of Customers that experience more than "n" sustained interruptions Total Number of Customers Served Propose "n" to be 5 sustained interruptions. Consistent with annual Service Quality Report, where customers experiencing more than 5 sustained interruptions in a year receive $50 bill credit. **Order Point:** Direct Xcel to use a Normalization method consistent with the Commission's most recent Order in the Annual Service Quality, Safety, and reliability docket in reporting their SAIDI, SAIFI, CAIDI, CELID, and ASAI within this docket.	A $50 credit to customers experiencing six or more interruptions in a year; Provides a credit for customers who have continuously resided at an address experiencing consecutive years of interruptions according to the below terms: • A $75 credit to customers experiencing five or more interruptions in two consecutive years; • A $100 credit to customers experiencing four or more interruptions in three consecutive years; and • A $125 credit to customers experiencing four or more interruptions in four or more consecutive years. * Large municipal pumping customers on the A41 Tariff receive $200 credits for each outage unrelated to MEDs lasting more than one minute per year. Similarly, small municipal pumping customers on the A40 Tariff receive $100 credits for each outage unrelated to MEDs lasting more than one minute per year.	Approved by PUC Order	Underperformance Penalty in QSP Tariff	All Days: 0.786% Annual Rules Normalized: 0.421%	All Days: 0.674% Annual Rules Normalized: 0.467%	All Days: 0.538% Annual Rules Normalized: 0.366%	All Days:0.450 % Annual Rules Normalized: 0.137%	All Days: 0.699% Annual Rules Normalized: 0.591%	All Days: 0.523% Annual Rules Normalized: 0.231%
6	Average Service Availability Index (ASAI): Similar to SAIDI - is percentage of time service is available. (Whereas SAIDI is average total amount of time service is unavailable.)	Reported Prior to PBR	Report with and without major event days: Customer Hours Service Availability Customer Hours Service Demanded **Order Point:** Direct Xcel to use a Normalization method consistent with the Commission's most recent Order in the Annual Service Quality, Safety, and reliability docket in reporting their SAIDI, SAIFI, CAIDI, CELID, and ASAI within this docket.	99.9824%	Annual Rules Normalized: Baseline set to the three-year average		All Days: 99.9649% Annual Rules Normalized: 99.9829%	All Days: 99.9752% Annual Rules Normalized: 99.9831%	All Days: 99.9745% Annual Rules Normalized: 99.9812%	All Days: 99.9763% Annual Rules Normalized: 99.9846%	All Days: 99.9762% Annual Rules Normalized: 99.9817%	All Days: 99.9730% Annual Rules Normalized: 99.9857%
7	Momentary Average Interruption Frequency Index ($MAIFI_E$): The amount of momentary interruptions a customer would experience during a period of time.	Reported Prior to PBR, but not with AMI technology. Propose and Tracking in 2026, Report in 2027	Report with and without major event days: Sum of Total Momentary Customer Interruptions Total Number of Customers Served Momentary events = having duration of less than or equal to 5 minutes.	NA			Discussion in narrative.	Discussion in narrative.	Discussion in narrative.	NA	NA	NA
8	Power Quality	New, once AMI capacilities are determined. Propose and Tracking in 2026, Report in 2027	None currently. Could be tracked, and percent of customer exceptions can be reported with AMI data. Specific capabilities still being developed and will be determined over the coming years.	NA			Discussion in narrative.	Discussion in narrative.	Discussion in narrative.	NA	NA	NA
9	Equity- Locational Reliability	NEW; Moved back from Service Quality in 2023	TBD	NA								
Customer Service Quality												
1	Existing multi-sector metrics, including ACSI and J.D. Power (NSPM)	Began in 2020 PBR Report	Reporting from Xcel Energy's subscription to J.D. Power and public information published by ACSI.	None	Customer Satisfaction score are subjective to an immeidate issue may vary from year to year. The same customer base may not be interviewed from one year to the next, providing inconsistent results. We requested removal of ACSI.		J.D. Power discussion in narrative. ACSI Study: https://www.theacsi.org/index.php?option=com_content&view=article&id=149&catid=&Itemid=214&i=Investor-Owned+Energy+Utilities	J.D. Power discussion in narrative. ACSI Study: https://www.theacsi.org/index.php?option=com_content&view=article&id=149&catid=&Itemid=214&i=Investor-Owned+Energy+Utilities	J.D. Power discussion in narrative. ACSI Study: https://www.theacsi.org/index.php?option=com_content&view=article&id=149&catid=&Itemid=214&i=Investor-Owned+Energy+Utilities	NA	NA	NA
2	Call center response time: Measures telephone response time.	Reported Prior to PBR	Calls answered by a call center representative within 20 seconds + all calls handled via self-service in the Interactive Voice Response (IVR) system Total calls into our call centers or business office	80% of call answered in 20 seconds or less - includes Residential, BSC, Credit, PAR, all calls handled by IVR.	Approved by PUC Order	Underperformance Penalty in QSP Tariff	84.59%	82.90%	85.8%	90.80%	91.12%	90.10%
3	Billing invoice accuracy: Measures percent of accurate invoices Xcel Energy issues to customers.	Reported Prior to PBR	Number of invoices canceled for controllable reasons Total number of invoices issued "Controllable reasons" = human errors made by field or office personnel, billing system and metering system communications errors, and malfunctioning meter equipment.	% of correctly billed invoices greather than or equal to 99.3%.	Approved by PUC Order	Underperformance Penalty in QSP Tariff	47,452 controllable cancel rebills in 2022, 25,258,502 invoices sent in 2022. Data is from M2M Detailed Reports 47,452/25,258,502 = 99.81% accurate	37,222 controllable cancel rebills in 2021, 24,936,261 invoices sent in 2021. Data is from M2M Detailed Reports 37,222/24,936,261 = 99.85% accurate	39,983 controllable cancel rebills in 2020, 21,702,130 invoices sent in 2020. Data is from M2M Detailed Reports 39,983/21,702,130 = 99.82% accurate	35,358 controllable cancel rebills in 2019, 24,193,752 invoices sent in 2019. Data is from M2M Detailed Reports 35,358/24,193,752 = 99.83% accurate	29,894 controllable cancel rebills in 2018, 21,222,643 invoices sent in 2018. Data is from M2M Detailed Reports 29,894/21,222,643 = 99.86% accurate	39,196 controllable cancel rebills in 2017, 21,029,969 invoices sent in 2017. Data is from M2M Detailed Reports 39,196/21,029,969 = 99.85% accurate
4	Number of customer complaints: Measures number of complaints based on number of complaints per 1,000 customers to regulatory agencies to ensure performance is measured in relation to total customer base.	Reported Prior to PBR	Number of MPUC Complaints < Number of Customers/1000 x 0.2059	Value adjusts annually	Approved by PUC Order	Underperformance Penalty in QSP Tariff	1,823,353/ 1000 x 0.2059= 375 330 MPUC complaints by Xcel Energy < 375 2022 Threshold per QSP calculation The calculation for the per 1000 customers is: 1,823,353 Customers/1000 = 1823.353 number of complaints 330: Calculation 330/1823.353 =.1810 which is less than the .2059 threshold.	1,803,744/ 1000 x 0.2059= 371 257 MPUC complaints by Xcel Energy < 371 2021 Threshold per QSP calculation The calculation for the per 1000 customers is: 1,803,744 Customers/1000 = 1803.744 number of complaints 257: Calculation 257/1803.744 =.1425 which is less than the .2059 threshold.	1,782,621/ 1000 x 0.2059= 367 239 MPUC complaints by Xcel Energy < 367 2020 Threshold per QSP calculation The calculation for the per 1000 customers is: 1,782,621 Customers/1000 = 1782.621, number of complaints 239: Calculation 239/1782.621 =.1341 which is less than the .2059 threshold.	1,765,013/ 1000 x 0.2059= 363 396 MPUC complaints by Xcel Energy > 367 2019 Threshold per QSP calculation The calculation for the per 1000 customers is: 1,765,013 Customers/1000 = 1765.013, number of complaints 396: Calculation 396/1765.013 =.2243 which is more than the .2059 threshold.	1,749,615/ 1000 x 0.2059= 360 248 MPUC complaints by Xcel Energy < 360 2018 Threshold per QSP calculation The calculation for the per 1000 customers is: 1,749,615 Customers/1000 = 1749.615 number of complaints 248: Calculation 248/1749.615 =.1417 which is less than the .2059 threshold.	1,734,941/1000 x 0.2059= 357 113 MPUC complaints by Xcel Energy < 357 2017 Threshold per QSP calculation The calculation for the per 1000 customers is: 1,734,941 Customers/1000 = 1734.941, number of complaints 113: Calculation 113/1734.941 =.0651 which is less than the .2059 threshold.

OUTCOME	COMMISSION-APPROVED METRIC	Reporting Status	APPROVED CALCULATION METHOD REPORT ANNUALLY	Proposed Baseline Calculation	Reference	Target	2022	2021	2020	2019	2018	2017
Environmental Performance												
1	Total carbon emissions by: (1) utility-owned facilities and PPAs and (2) all sources	Began in 2020 PBR Report	Leverage Xcel Energy reporting to The Climate Registry (TCR) by data "pools." • Pool 1 = owned zero-emission facilities • Pool 2 = owned fossil electric generating units (EGUs) equipped with continuous emission monitoring systems (CEMS) • Pool 3 = owned fossil EGUs not equipped with CEMS • Pool 4 = purchased power agreements (PPAs) • Pool 5 = short-term and spot-purchased power from known sources (to which we can ascribe a specific emissions) • Pool 6 = short-term and spot-purchased power from unknown sources in MISO market (to which we cannot ascribe a specific emissions rate so apply regional grid average CO2 rates from EPA). In calculating total carbon emissions from utility-owned facilities and PPAs only, include Pools 1-4 only. In calculating emissions from all sources, include Pools 1 through 6. We include CO2 from MISO market purchases, but deduct CO2 from trade margin sales, since this energy does not serve customers, and if energy purchasers report this CO2, would result in double-counting.	Company proposes to establish CO2 mass emissions baseline utilizing our most recent Integrated Resource Plan (IRP) consistent with standards yet to be established with the State of Minnesota's carbon-free electricity standard requirements	IRP as approved by PUC; The Commission recently initiated investigation into the Carbon Free Standard and will issue orders neessary for utilities to comply with resolution of the docket anticipated in 2025.	Company proposes to establish future CO2 mass emissions target utilizing our most recent Integrated Resource Plan (IRP) consistent with standards yet to be established with the State of Minnesota's carbon-free electricity standard requirements.	(a) Utility-owned facilities and PPAs = 12,612,098 tons (b) All sources = 12,649,295 tons.	(a) Utility-owned facilities and PPAs = 13,729,970 tons (b) All sources = 13,800,098 tons.	(a) Utility-owned facilities and PPAs = 12,710,943 tons (b) All sources = 12,801,300 tons.	(a) Utility-owned facilities and PPAs = 15,193,303 tons (b) All sources = 16,229,466 tons	(a) Utility-owned facilities and PPAs = 17,132,871 tons (b) All sources = 18,549,479 tons	(a) Utility-owned facilities and PPAs = 17,537,080 tons (b) All sources = 18,891,471 tons
2	Carbon intensity (emissions per MWh) by: (1) utility-owned facilities and PPAs and (2) all sources	Began in 2020 PBR Report	For carbon intensity from utility-owned facilities and PPAs only, divide total CO2 from Pools 1-4 by total generation (MWh) for resources in those pools to derive CO2 intensity in pounds per MWh. For carbon intensity from all sources, divide total CO2 from Pools 1-6 by total generation (MWh) for resources in those pools to derive CO2 intensity in pounds per MWh. We include CO2 from MISO market purchases, but deduct CO2 from trade margin sales, since this energy does not serve customers, and if energy purchasers report this CO2, would result in double-counting.	Company is not proposing a baseline metric for carbon intensity. This would be unnecessary, as it is tied to the total carbon dioxide reduction metric.	NA		(a) Utility -owned facilities and PPAs = 602 pounds per MWh (b) All sources = 603 pounds per MWh.	(a) Utility -owned facilities and PPAs = 667 pounds per MWh (b) All sources = 669 pounds per MWh.	(a) Utility -owned facilities and PPAs = 640 pounds per MWh (b) All sources = 643 pounds per MWh.	(a) Utility-owned facilities and PPAs = 760 pounds per MWh (b) All sources = 786 pounds per MWh	(a) Utility-owned facilities and PPAs = 829 pounds per MWh (b) All sources = 857 pounds per MWh	(a) Utility-owned facilities and PPAs = 865 pounds per MWh (b) All sources = 893 pounds per MWh
3	Total criteria pollutant emissions	Began in 2020 PBR Report	Report criteria pollutant information for utility-owned facilities only. Nitrous oxide (NOx) and sulfur dioxide (SO2) emissions are tracked based upon state and federal monitoring requirements. Various emissions monitoring methods are used, depending upon facility and pollutant, including CEMS, fuel flow and fuel analysis. For particulate matter (PM), emissions are tracked based on allowed state reporting methodologies including stack test data and use of EPA AP-42 emission estimates.	Company is not proposing a baseline metric for criteria pollutant mas emissions. This would be unnecessary, as it is tied to the total carbon dioxide reduction metric.	NA		• NOx: 6,802 tons • SO2: 3,354 tons • PM: 492 tons • Mercury: 0.0376 tons • Lead: 0.0635 tons Additional discussion in narrative	• NOx: 7,318 tons • SO2: 3,886 tons • PM: 541 tons • Mercury: 0.0378 tons • Lead: 0.0563 tons Additional discussion in narrative	• NOx: 6,050 tons • SO2: 3,356 tons • PM: 472 tons • Mercury: 0.0435 tons • Lead: 0.0532 tons Additional discussion in narrative	• NOx: 7,919 tons • SO2: 4,695 tons • PM: 554 tons • Mercury: 0.0375 tons • Lead: 0.0615 tons Additional discussion in narrative	• NOx: 9,550 tons • SO2: 6,634 tons • PM: 648 tons • Mercury: 0.0355 tons • Lead: 0.0730 tons Additional discussion in narrative	• NOx: 9843 tons • SO2 5728 tons • PM: 1006 tons • Mercury: 0.0325 tons • Lead: 0.0785 tons Additional discussion in narrative
4	Criteria pollutant emission intensity per MWh	Began in 2020 PBR Report	Track and report emissions of NOx, SO2 and PM as proposed for "Total criteria pollutant emissions," and then divide those figures by total MWh of generation to derive criteria pollutant emission intensity.	Company is not proposing a baseline metric for criteria pollutant intensity. This would be unnecessary, as it is tied to the total carbon dioxide reduction metric.	NA		• NOx: 0.439 pounds per MWh • SO2: 0.216 pounds per MWh • PM: 0.032 pounds per MWh • Mercury: 0.000002 pounds per MWh • Lead: 0.000004 pounds per MWh	• NOx: 0.479 pounds per MWh • SO2: 0.254 pounds per MWh • PM: 0.035 pounds per MWh • Mercury: 0.000002 pounds per MWh • Lead: 0.000004 pounds per MWh	• NOx: 0.416 pounds per MWh • SO2: 0.231 pounds per MWh • PM: 0.032 pounds per MWh • Mercury: 0.000003 pounds per MWh • Lead: 0.000004 pounds per MWh	• NOx: 0.509 pounds per MWh • SO2: 0.302 pounds per MWh • PM: 0.036 pounds per MWh • Mercury: 0.000002 pounds per MWh • Lead: 0.000004 pounds per MWh	• NOx: 0.575 pounds per MWh • SO2: 0.400 pounds per MWh • PM: 0.039 pounds per MWh • Mercury: 0.000002 pounds per MWh • Lead: 0.000004 pounds per MWh	• NOx: 0.619 pounds per MWh • SO2: 0.360 pounds per MWh • PM: 0.000002 pounds per MWh • Mercury: 0.000005 pounds per MWh • Lead: pounds per MWh
5(a)	CO2 emissions avoided by electrification of transportation – Alternative & Original approach	Began in 2020 PBR Report	Percent of EVs in Xcel Energy's MN service territory participating in managed charging programs or on whole-house TOU rates. Proposed formula:	9.3%	Rolling 3-year weighted average		• 10.84% Additional discussion in narrative.	• 8.61% Additional discussion in narrative.	7.23% Additional discussion in narrative.	6.16%	4.50%	3.39%
5(b)	CO2 emissions avoided by electrification of transportation – Alternative & Original approach	Began in 2020 PBR Report	Percent of managed charging customers' residential EV charging load occurring during off-peak hours. Proposed formula: Total annual energy consumed (MWh) by EVs charging during off-peak hours at the residences of customers enrolled in Xcel Energy's EV TOU rates or other managed charging programs Total annual energy consumed (MWh) by EVs charging at residences of customers enrolled in Xcel Energy's EV TOU rates or other managed charging programs	90.9%	Rolling 3-year weighted average		• 86.94% • 6,509.61 MWh • 7,487.12 MWh	• 89.5% • 4,847 MWh • 5,415 MWh	93.9% Additional discussion in narrative.	94.0%	92.8%	92.70%
5(c)	CO2 emissions avoided by electrification of transportation – Alternative & Original approach	Began in 2020 PBR Report	Calculation methodology has not changed this year and includes the following with additional detail given in the narrative: • Calculation of the total annual kWh consumption by EVs in the Company's Minnesota service territory. • Calculation of CO2 emissions from EV charging by multiplying the total annual kWh consumption by the system average CO2 rate per kWh, as reported annually to The Climate Registry and third-party verified. For EV customers who are also renewable energy tariff subscribers a rate of 0 lbs/kWh is assigned. • Calculation of CO2 that would have otherwise been emitted by gasoline vehicles for an equivalent number of miles traveled by EVs conservatively using data from DOE Alternative Fuels Data Center and EPA. • The CO2 avoidance metric is then calculated as the difference between emissions from annual EV use and displaced emissions that otherwise would have occurred from equivalent travel by gasoline vehicles.	71,410	Rolling 3-year weighted average		75,180 tons Additional discussion in narrative.	76,895 tons Additional discussion in narrative.	53,784 tons Additional discussion in narrative.	39,355 tons Additional discussion in narrative	31,376 tons Additional discussion in narrative	25,857 tons Additional discussion in narrative

OUTCOME	COMMISSION-APPROVED METRIC	Reporting Status	APPROVED CALCULATION METHOD REPORT ANNUALLY	Proposed Baseline Calculation	Reference	Target	2022	2021	2020	2019	2018	2017
6	CO2 emissions avoided by electrification of buildings, agriculture, and other sectors	Began in 2020 PBR Report	Calculate CO2 avoidance based on comparison of CO2 emitted to provide same service (water heating, space heating, etc.) with electricity vs. with fossil fuel. Proposed formula: (Annual average CO2 emissions from the fossil electric appliances) – ((energy (in kWh) consumed by the electric appliance) * (Xcel Energy's annual system average CO2 rate per kWh))	NA	NA		No quantitative results to report for 2022. Additional discussion in narrative re CIP/ECO and NGIA.	No quantitative results to report for 2021. Additional discussion in narrative.	No quantitative results to report for 2020 Additional discussion in narrative.	No quantitative results for 2019	No quantitative results for 2018	No quantitative results for 2017
7	Discussion of methane emissions, including proposed methodology for reporting	Began in 2020 PBR Report	Not included in proposed metrics and methodologies, but ordered by Commission (April 16, 2020 Order, order point 1.d) In Reply comments address our position i. Fresh Energy's proposed methane leakage rate value of 3%; the Department's recommended leakage rate of 1.87% (Department changed to .2% at the hearing); or None or <.2% based on reporting to the EPA under subpart W of the GHG Reporting Program.	Recommend Moving to Appropriate Gas Docket	PBR is an electric docket and not appropriate to set baselines or targets for our natural gas business. Commission opened a docket to establish integrated resource planning for natural gas distribution companies in 2023-2024.		In 2021 as reported to EPA Mandatory Greenhouse Gas Reporting Rule under Subpart W, the methane emission rates on the gas distribution system controlled by Xcel Energy was 0.121% for NSPM and 0.163% enterprise wide. Note that for this Environmental Performance metric only, the reported data is for 2021, not 2022, since Subpart W data for 2022 is not yet available as of April 2023. Additional discussion in narrative.	In 2020 as reported to EPA Mandatory Greenhouse Gas Reporting Rule under Subpart W, the methane emission rates on the gas distribution system controlled by Xcel Energy was 0.121% for NSPM and 0.146% enterprise wide. Note that for this Environmental Performance metric only, the reported data is for 2020 not 2021, since Subpart W data for 2021 is not yet available as of April 2022. Additional discussion in narrative.	In 2019 as reported to EPA Mandatory Greenhouse Gas Reporting Rule under Subpart W, the methane emission rates on the gas distribution system controlled by Xcel Energy was 0.107% for NSPM and 0.144% enterprise wide. Note that for this Environmental Performance metric only, the reported data is for 2019 not 2020, since Subpart W data for 2020 is not yet available as of April 2021. Additional discussion in narrative.	NA	NA	NA
8	Require Xcel Energy to include in its PBR annual reports information on: availability of data specific to its gas suppliers on upstream methane emissions; regulation of methane emissions upstream of the Company's distribution system, and the Company's position on such regulations; participation in voluntary initiatives to quantify and reduce methane from gas suppliers; any certified gas purchases; pilots with gas marketers to track and source gas with lower associated methane emissions; and any other actions the Company has taken to secure data on and/or reduce upstream methane emissions. No later than 2024, the Company will re-evaluate data available on upstream methane to consider feasibility of reporting of methane emissions attributable to total natural gas purchases across the full fuel cycle (from drilling and extraction to the end-use).	Began in 2021 PBR Report	__________	Recommend Moving to Appropriate Gas Docket	PBR is an electric docket and not appropriate to set baselines or targets for our natural gas business. Commission opened a docket to establish integrated resource planning for natural gas distribution companies in 2023-2024.		Additional Discussion in narrative.	Additional Discussion in narrative.	New metric for 2021. Nothing reported for 2020.	NA	NA	NA
9	Once the Commission has determined adequate data on upstream methane is available to support utility-specific reporting of such emissions, methane emissions across the full fuel cycle in its calculation of greenhouse gas emissions avoided by electrification of buildings, agriculture, and other sectors.	New / TBD	__________	Recommend Moving to Appropriate Gas Docket	PBR is an electric docket and not appropriate to set baselines or targets for our natural gas business. Commission opened a docket to establish integrated resource planning for natural gas distribution companies in 2023-2024.		We do not report yet.	We do not report yet.	New metric for 2021. Nothing reported for 2020.	NA	NA	NA
Cost Effective Alignment of Generation and Load												
1	Demand response, including (1) capacity available (MW & MWh) and (2) amount called (MW, MWh per year)	Reported Prior to PBR	System Generated	Total Capacity Available 764 Gen. MW and 156,189 MWh (Actual based on called events)	Baseline projected for available capacity. Energy measurements are based on capacity numbers.		(1)Total Capacity Available in MN 772 Gen. MW and 165,134 Gen. MWh. (2) Total Actual Capacity called (2022) 0 Gen. MW and 1,671 Gen. MWh.	(1)Total Capacity Available in MN (summer 2021) 764 Gen. MW and 147,466 Gen. MWh. (2) Total Actual Capacity called (2020) 0 Gen. MW and 2,192 Gen. MWh.	Total Capacity Available in MN (summer 2020) 755 Gen. MW and 155,967 Gen. MWh. Total Actual Capacity called (2020) 0 Gen. MW and 1,066 Gen. MWh.	Total Capacity Available in MN (summer 2019) 749 Gen. MW and 165,807 Gen. MWh. Total Actual Capacity called (2019) 0 Gen. MW and 2,633 Gen. MWh.	Total Capacity Available in MN (summer 2018) 718 Gen. MW and 150,451 Gen. MWh. Total Actual Capacity called (2018) 4 Gen. MW and 576 Gen. MWh.	Total Capacity Available in MN (summer 2017) 658 Gen. MW and 134,140 Gen. MWh. Total Actual Capacity called (2017) 342 Gen. MW and 755 Gen. MWh.
2	Integration of customer loads with utility supply - Amount of demand response that SHAPES customer load profiles through price response, time varying rates, or behavior campaigns.	New / TBD	Actual MW at system peak hour before and after rate initiation or the start of a behavioral program. As these programs mature it, will be necessary to determine how participants load would have grown over time without the program. Forecasted load avoided will be based on actual trends over time.	N/A	Current TOU pilot showed no measureable impact on demand reduction as a Shaping measure.		Shaping activities such as fuel switching and time of use rates are still being reviewed as part of our pilot efforts; the first results of the residential pilot were filed on Feb. 10, 2023 in Docket No. E002/M-17-775.	Shaping activities such as fuel switching and time of use rates are still being reviewed as part of our pilot efforts. Additional discussion in narrative.	Shaping activities such as fuel switching and time of use rates are still being reviewed as part of our pilot efforts. Additional discussion in narrative.	NA	NA	NA
3	Integration of customer loads with utility supply - Amount of demand response that SHIFTS energy consumptions from times of high demand to times when there is a surplus of renewable generation.	New / TBD	Available MWh during times contingency events and/or shifts to particular times of the day over time. Calculations would likely be based on assumptions until a larger population of customers can be analyzed through a measurement and verification process to verify reduction in load. This calculation is the only demand respond type that will not forecast specific load – only actual shifting will be measured.	N/A	No current programs to baseline against. Current pilots being tested along with load shifting measures as part of Docket No. E, G002/CIP-23-92.		Shifting activities such as fuel switching are still being reviewed as part of our pilot efforts . Additional discussion in narrative.	Shifting activities such as fuel switching and time of use rates are still being reviewed as part of our pilot efforts . Additional discussion in narrative.	Shifting activities such as fuel switching and time of use rates are still being reviewed as part of our pilot efforts. Additional discussion in narrative.	NA	NA	NA

OUTCOME	COMMISSION-APPROVED METRIC	Reporting Status	APPROVED CALCULATION METHOD REPORT ANNUALLY	Proposed Baseline Calculation	Reference	Target	2022	2021	2020	2019	2018	2017
4(a)	Integration of customer loads with utility supply - Amount of demand response that SHEDS loads that can be curtailed to provide peak capacity and supports the system in contingency events - for Available Load	Began in 2020 PBR Report	Customers with interval data to determine the actual potential demand reduction during an event, the Company completes an analysis of actual event data collected from interval data. This analysis includes the following and may differ slightly by program: • Collection of interval data (typically five years of data is analyzed at one time); • Assign day of week and holidays to hourly data; • Update hourly load relief by customer (by contract); • Subtract firm kW to estimate potential load relief by hour; • Calculate an average 24-hour profile by month for each customer which excludes weekends, holidays and event days; • Gather 10 years of system peak system data to determine the most common peak hour by month based on frequency; and • Average the controllable load kW for each customer using the most common peak hours by month using weekdays (excluding holidays and weekends) in a given year. For customers without interval data (such as those for residential), every control season data is gathered from installed sample sites to determine load reduction capability for all Savers Switch participants. At the end of the control season we gather data for each sample point along with the corresponding weather for the control season year to use in our load management analysis.	Total Capacity Available 764 Gen. MW and 156,189 MWh	Baseline projected for available capacity. Energy measurements are based on capacity numbers.		(1)Total Capacity Available in MN 772 Gen. MW and 165,134 Gen. MWh. (2) Total Actual Capacity called (2022) 0 Gen. MW and 1,671 Gen. MWh.	Total Capacity Available in MN (summer 2021) 764 Gen. MW and 147,466 Gen. MWh.	Total Capacity Available in MN (summer 2020) 755 Gen. MW and 155,967 Gen. MWh.	Total Capacity Available in MN (summer 2019) 749 Gen. MW and 165,807 Gen. MWh.	Total Capacity Available in MN (summer 2018) 718 Gen. MW and 150,451 Gen. MWh.	Total Capacity Available in MN (summer 2017) 658 Gen. MW and 134,140 Gen. MWh.
4(a) continued			The steps to produce the forecast of potential load relief are below: • We forecast potential load relief for each sample customer by simulating interruptions for each hour given the two types of cycling strategies. The estimated potential load relief kW per customer is the difference between the observed load and the assumed cycling strategy of smart and standard switches. We estimate the potential load relief for all hours during the collection period (using the most current year data) by estimating the allowed hourly duty cycle that would be achieved by control and subtracting it from the observed kW load. The allowed duty cycle represents a simulation of the load level the AC would be controlled down to. • We then average these individual load relief estimates per hour per customer class - residential or commercial. Next, using the average sample customer load relief estimates for the group from non-interrupt days across the summer, we build linear regression models with regressing sample load relief estimates against Temperature Humidity Index (using a rolling 5 year timeframe). • From those regressions, a final model is selected based on statistical merit, to which we then apply corresponding system peaking weather conditions to derive a kW per customer load relief value.	Continued	Continued							
4(b)	Integration of customer loads with utility supply - Amount of demand response that SHEDS loads that can be curtailed to provide peak capacity and supports the system in contingency events - for Actual Load Reduction Achieved	Began in 2020 PBR Report	Actual load relief is determined by measurements of load during an event. We measure actual load by hour compared to the delta between the actual load and the estimated load that would have occurred without the interruption. This metric will be broken up by event for emergency and contingency events.	Total Capacity Available 764 Gen. MW and 156,189 MWh	Baseline projected for available capacity. Energy measurements are based on capacity numbers.		(1)Total Capacity Available in MN 772 Gen. MW and 165,134 Gen. MWh. (2) Total Actual Capacity called (2022) 0 Gen. MW and 1,671 Gen. MWh.	Total Actual Capacity called (2020) 0 Gen. MW and 2,192 Gen. MWh.	Total Actual Capacity called (2020) 0 Gen. MW and 1,066 Gen. MWh.	Total Actual Capacity called (2019) 0 Gen. MW and 2,633 Gen. MWh.	Total Actual Capacity called (2018) 4 Gen. MW and 576 Gen. MWh.	Total Actual Capacity called (2017) 342 Gen. MW and 755 Gen. MWh.
4(c)	Metrics that measure the effectiveness and success of items above, individually and in aggregate.	Began in 2020 PBR Report	Load factor for load net of variable renewable generation. Measurement will help determine how well Xcel Energy is shaping load to integrate with most cost-effective supply including demand response, energy efficiency and DERs. The closer to one the measurement is, the more load is being shaped.	None	Requested to remove this metric.		40.50%	41.20%	46.79% Annual Load Factor for load net of renewable generation (w/o Hydro being considered renewable) Additional discussion in narrative.	52.05%	51.68%	51.72%
Workforce Community Development												
1	Workforce plan with data relative to plant closures to analyze attrition, skill gaps, workforce impacts, etc., and plan to address impacts as result of plant closures.	Began in 2021 PBR Report	Submit a draft comprehensive and prescriptive workforce transition plan annually and leading up to the closure of each coal fired generating unit. The "workforce transition plan" (WFTP) will include forecasted attrition, workforce impacts, solutions, and estimated solution costs. The report will evolve and forecasts will be refined as each plant nears closure, based on an employees aspirations and the decisions they choose for themselves. Per Commission Order, the Company will perform outreach to additional labor organizations and other representative organizations for feedback on the Plan.	None	Requested to move this duplicative reporting to IRP Docket.		Discussion in narrative	Discussion in narrative	Transition Plan proposal in 2020 report narrative.	N/A	NA	NA
Stakeholder Discussions												
1	PUBLIC DASHBOARD: Require the Company to host one or more stakeholder meetings for stakeholders to ask questions and provide feedback about the proposed scorecard.	New / TBD	__________	NA	NA		Discussion in narrative.	Stakeholder discussion held on February 22, 2022 in compliance with MPUC Order.	Discussion in narrative.	NA	NA	NA
2	DEMAND RESPONSE PERFORMANCE INCENTIVE: Develop and file a demand response incentive Commission consideration by Q1 2021.	New / TBD	__________	NA	NA		Discussion in narrative.	Discussion in narrative.	Discussion in narrative.	NA	NA	NA
3	EVALUATION CRITERIA AND BENCHMARKS: Commission to direct Xcel Energy to begin development of evaluation criteria and benchmarks 2023 after the 2022 annual report is filed.	New / TBD	The Commission will direct Xcel to work with stakeholders to develop evaluation criteria and benchmarks and file them at a later date. The Commission will wait until the appropriate step in the PIM process to decide on criteria for good versus bad performance, and establish benchmarks against which to measure Xcel's performance; however, the process of evaluating such criteria and benchmarks is likely to be complex and time-consuming, and the Commission will direct Xcel and stakeholders to begin that process.	NA	NA		Discussion in narrative.	Discussion in narrative.	Discussion in narrative.	NA	NA	NA

CERTIFICATE OF SERVICE

I, Ella Giefer, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

DOCKET NO. E002/CI-17-401

Dated this 31st day of July 2023

/s/

____

Ella Giefer
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
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Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_17-401_Official
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